BART Determination 11/18/09
for
Stanton Station Unit 1

I. Source Description

A. Owner/Operator: Great River Energy

B. Source Type: Electric Utility Steam Generating Unit

C. BART Eligible Units
1. Unit 1 boiler
2. Auxiliary Boiler
3. Emergency Diesel Generator
4. Emergency Fire Pump Engine
5. Materials Handling Equipment
a. Unit 1 coal bunker
b. Flyash silo

D. Unit Description

1. Unit 1:
Generator Nameplate Capacity: 188 MWe
Boiler Rating: 1,800 x 10^6 Btu/hr
Startup: 1966
Fuel: North Dakota Lignite, PRB Subbituminous
Firing Method: Wall-fired
Existing Air Pollution Control Equipment: Low NO_x burners and an electrostatic precipitator

2. Auxiliary Boiler:
Boiler Rating: 38 x 10^6 Btu/hr
Fuel: #2 fuel oil

3. Emergency Diesel Generator
Rating: 10.35 x 10^6 Btu/hr
Fuel: #2 fuel oil

4. Emergency Fire Pump Engine:
Rating: 370 horsepower
Fuel: #2 fuel oil

5. Materials Handling Equipment:

a. Unit 1 coal bunker
Existing Air Pollution Control Equipment: Baghouse

b. Flyash Silo:
Existing Air Pollution Control Equipment: Baghouse

E. Emissions

BART Eligible Unit	**Pollutant**	**2000**	**2001**	**2002**	**2003**	**2004**	**2000-2004 Avg.**
Unit 1 Boiler (lignite coal)	SO_2 (tons) SO_2 (lb/10^6 Btu) NO_x (tons) NO_x (lb/10^6 Btu) PM (tons) PM (lb/10^6 Btu)	7,660 1.70 1,849 0.41 86 0.019	9,046 1.82 2,044 0.41 95 0.019	8,548 1.59 2,312 0.43 70 0.013	8,084 1.81 1,961 0.44 53 0.012	7,871 1.52 2,073 0.40 63 0.012	8,242 1.70 2,048 0.42 73.4 0.016
Unit 1 Boiler (PRB coal)	SO_2 (tons) SO_2 (lb/10^6 Btu) NO_x (tons) NO_x (lb/10^6 Btu) PM (tons) PM (lb/10^6 Btu)	* * * * * *	* * * * * *	* * * * * *	* * * * * *	* * * * * *	6,216** 1.2** 1,740** 0.36** 91** 0.019**
Auxiliary Boiler	SO_2 (tons) NO_x (tons) PM (tons)	* * *	* * *	* * *	* * *	* * *	0.36 0.14 0.02
Emergency Diesel Generator	SO_2 (tons) NO_x (tons) PM (tons)	* * *	* * *	* * *	* * *	* * *	1.3*** 8.0*** 0.2***
Emergency Fire Pump Engine	SO_2 (tons) NO_x (tons) PM (tons)	* * *	* * *	* * *	* * *	* * *	0.19*** 2.76*** 0.2***
Unit 1 Coal Bunker	PM (tons)	*	*	*	*	*	0.6****
Flyash Silo	PM (tons)	*	*	*	*	*	18.3****

* See A2000-2004 Avg.@ column.
** Projected emission rates when burning PRB coal (see discussion in Section IV.A. of this analysis for sulfur dioxide and Section IV.D. of this analysis for nitrogen oxides). For PM, it is assumed that PM emissions from the combustion of PRB coal are the same as for lignite coal.
*** Based on 500 hours per year of operation.
**** Department estimate.

II. Site Characteristics

The Stanton Station is located on the banks of the Missouri River in eastern Mercer County near the town of Stanton, North Dakota.

III. BART Evaluation of Unit 1 When Combusting Lignite Coal

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer / Fabric Filter (SD/FF)
Circulating Dry Scrubber
Wet Scrubber with a 10% bypass
Dry Sorbent Injection / Fabric Filter (DSI/FF)
Dry Sorbent Injection / Existing ESP (DSI/ESP)
Powerspan ECO7
Coal Cleaning
Pahlman Process™
K-Fuel7

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel7 is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from North Dakota was tested. The use of the K-Fuel process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel process available or technically and economically feasible.

A circulating dry scrubber is not considered commercially available by Great River Energy. However, the Department is including this as an available technology. Costs for a circulating dry scrubber are estimated based on cost estimates included in other BART analyses.

The Department considers the Powerspan ECO technology and the Pahlman Process not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

The Department has calculated the baseline SO_2 emission rate when burning lignite by utilizing the highest calendar year average SO_2 emission rate of 1.81 lb/million Btu from 2000-2004 and multiplying this value by the highest heat input for any two consecutive years for the 2000-2004 period. This results in a baseline SO_2 emission rate as follows:

Heat input (2001) = 9.965×10^{12} Btu

Heat input (2002) = 1.075×10^{13} Btu

Average heat input = $(9.965 \times 10^{12} + 1.075 \times 10^{13}) / 2$
= 1.036×10^{13} Btu

Baseline SO_2 emission rate when combusting lignite coal
= 1.036×10^{13} Btu (1.81 lb/million Btu)(1 ton/2000 lb) = 9,376 tons/year

The control effectiveness of all remaining control technologies are shown in the following table.

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Controlled Emissions**	
			(tons/yr)	**($lb/10^6$ Btu)**
Wet Scrubber	95	9,376	469	0.091
Circulating Dry Scrubber	93	9,376	656	0.127
SD/FF	90	9,376	938	0.181
Flash Dryer Absorber	90	9,376	938	0.181

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Controlled Emissions	
			(tons/yr)	($lb/10^6$ Btu)
Wet Scrubber with 10% bypass	86	9,376	1,313	0.263
DSI/FF	55	9,376	4,219	0.817
DSI/ESP	35	9,376	6,094	1.18

The cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Wet Scrubber	8,907	13,180,000	1,480	4,179****
Circulating Dry Scrubber	8,720	14,220,000***	1,631	10,638
SD/FF	8,438	11,220,000	1,330	850**
Wet Scrubber with 10% bypass	8,063	9,490,000	1,177	365
DSI/FF	5,157	8,430,000	1,635	2,789
DSI/ESP	3,282	3,200,000	975	---

Note: Flash Dryer Absorber not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Great River Energy (except as noted).
** The incremental cost shown is the incremental cost of SD/FF compared to DSI/FF.
*** The cost is estimated based on other BART analyses.
**** The incremental cost shown is the incremental cost of a wet scrubber compared to SD/FF.

Step 4: Evaluate Impacts and Document Results

Great River Energy has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the control equipment.

Step 5: Evaluate Visibility Results

The two primary alternatives are a wet scrubber operating at 95% removal efficiency and a spray dryer operating at 90% efficiency. The effects on visibility for each of these two control options at the Theodore Roosevelt National Park, South Unit (TRNP-SU), Theodore Roosevelt National Park, North Unit (TRNP-NU), Theodore Roosevelt National Park, Elkhorn Ranch (TRNP-Elkhorn Ranch) and the Lostwood Wilderness Area (Lostwood WA) are shown in the following tables.

Unit 1 - Lignite Coal Combustion Delta Deciview 90th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.066	0.048	0.018
2001	TRNP-SU	0.061	0.043	0.018
2002	TRNP-SU	0.096	0.089	0.007
Average	TRNP-SU			0.014
2000	TRNP-NU	0.080	0.062	0.018
2001	TRNP-NU	0.089	0.061	0.028
2002	TRNP-NU	0.097	0.072	0.025
Average	TRNP-NU			0.024
2000	TRNP-Elkhorn Ranch	0.054	0.040	0.014
2001	TRNP-Elkhorn Ranch	0.036	0.024	0.012
2002	TRNP-Elkhorn Ranch	0.074	0.050	0.024
Average	TRNP-Elkhorn Ranch			0.017
2000	Lostwood WA	0.118	0.094	0.024
2001	Lostwood WA	0.160	0.139	0.021
2002	Lostwood WA	0.088	0.078	0.01
Average	Lostwood WA			0.019
	Overall Average			0.019

Unit 1 - Lignite Coal Combustion Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.320	0.290	0.03
2001	TRNP-SU	0.322	0.270	0.052
2002	TRNP-SU	0.668	0.556	0.112
Average	TRNP-SU			0.065
2000	TRNP-NU	0.458	0.369	0.089
2001	TRNP-NU	0.385	0.334	0.051
2002	TRNP-NU	0.595	0.516	0.079
Average	TRNP-NU			0.073
2000	TRNP-Elkhorn Ranch	0.224	0.183	0.041
2001	TRNP-Elkhorn Ranch	0.241	0.178	0.063
2002	TRNP-Elkhorn Ranch	0.517	0.429	0.088
Average	TRNP-Elkhorn Ranch			0.064
2000	Lostwood WA	0.340	0.320	0.02
2001	Lostwood WA	0.526	0.449	0.077
2002	Lostwood WA	0.410	0.341	0.069
Average	Lostwood WA			0.055
	Overall Average			0.064

Step 6: Select BART

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The incremental cost of greater than $10,600 per ton of sulfur dioxide removed for a circulating dry scrubber compared to a spray dryer is considered excessive and a circulating dry scrubber is removed from further consideration as BART.

The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. The degree of visibility improvement achieved by selecting a wet scrubber operating at 95% control efficiency versus a spray dryer operating at 90% control efficiency does not exceed 0.028 deciviews (90^{th} percentile) or 0.112 deciviews (98% percentile) at any Class I area for the 2000-2002 time frame. Although the amount of visibility improvement achieved by selecting a wet scrubber versus a spray dryer is small, the Department has placed the primary emphasis on the cost of each option. The incremental cost from a spray dryer to a wet scrubber is $4,179 per ton of SO_2 removed. The Department does not consider this incremental cost to be excessive. However, wet scrubbing does have additional environmental impacts when compared to a spray dryer with a fabric filter as outlined below:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.
- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.
- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Based upon the additional environmental impacts and the fact that a wet scrubber will remove at best an additional 469 tons/year of SO_2 (with a small corresponding visibility improvement) beyond the control achieved by a spray dryer, the Department proposes BART as a spray dryer with a fabric filter.

The highest <u>calendar year</u> average SO_2 emission rate is approximately 1.81 lb/MM Btu for the 2000-2004 period when combusting lignite at Stanton Station Unit 1. Utilizing a 90% control efficiency for the spray dryer and fabric filter results in an <u>annual average</u> controlled emission rate of approximately 0.181 lb/MM Btu. Based upon historical SO_2 emissions data for spray dryers and fabric filters at North Dakota facilities, the Department has determined that an increase of 33% is warranted to adjust from an <u>annual average</u> SO_2 emission rate to a <u>30-day rolling average</u> SO_2 emission rate. Multiplying the annual average emission rate of 0.181 lb/MM Btu by a factor of 1.33 (an increase of 33%) yields a <u>30-day rolling average</u> SO_2 emission rate of 0.24 lb/MM Btu. Therefore, BART for SO_2 when combusting lignite coal is an SO_2 emission limit of 0.24 lb/million Btu heat input (on a 30 day rolling average) or a reduction efficiency of 90% (on a 30 day rolling average) on the inlet SO_2 concentration to the pollution control equipment.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator (ESP)
New Wet ESP
Existing ESP

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency	Emissions	
		(tons/yr)	(lb/10^6 Btu)
Baghouse	99.7+	72.5	0.015
New ESP	99.7	72.5	0.015
Wet ESP	99.7	72.5	0.015
Baseline (Existing ESP)*	.99.5	90.5	0.019

* Based on the average of 2000 and 2001 emissions.

Alternative	Emissions Reduction (tpy)*	Annualized Cost ($)**	Cost Effectiveness ($/ton)
Baghouse	18	4,980,000	276,670
New ESP	18	5,800,000	322,220
Wet ESP	18	2,030,000	112,780
Baseline (Existing ESP)	0	0	---

* Reductions from the baseline emission rate.
** Costs provided by Great River Energy.

Step 4: Evaluate Impacts and Document the Results

Great River Energy has evaluated the energy and non-air quality effects of each option. The Department has determined that the effects will not preclude the selection of any of the options.

Step 5: Evaluate Visibility Impacts

Modeling was conducted to determine the visibility impairment at the PM emission limit of 0.1 lb/million Btu and an emission limit of 0.015 lb/million Btu. The visibility improvement in deciviews which results from reducing PM emissions from 0.1 lb/million Btu to 0.015 lb/million Btu is shown in the following table.

Unit 1 - Lignite Coal Combustion PM Delta Deciview			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.005	0.008
2001	TRNP-SU	0.001	0.002
2002	TRNP-SU	0.006	0.021
Average		0.004	0.01
2000	TRNP-NU	0.001	0.011
2001	TRNP-NU	0.005	0.006
2002	TRNP-NU	0.001	0.019
Average		0.002	0.012
2000	TRNP-Elkhorn Ranch	0.001	0.013
2001	TRNP-Elkhorn Ranch	<0.001	0.002
2002	TRNP-Elkhorn Ranch	0.001	0.01
Average		<0.001	0.008
2000	LWA	0.005	0.011
2001	LWA	0.007	0.007
2002	LWA	0.005	0.003
Average		0.006	0.007
Overall Average		0.003	0.009

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is a wet ESP. This system has a cost effectiveness of approximately $113,000 per ton of particulate when compared to the current emission control system (ESP operating at 99.5% efficiency). The Department considers this cost to be excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit is equipped with an electrostatic precipitator that is achieving 99.5% Control efficiency. The plant is expected to have a remaining useful life of at least 20 years.

If the particulate emitted was reduced from the allowable emission limit of 0.1 lb/million Btu to 0.015 lb/million Btu, the most improvement in visibility at any Class I area would be approximately 0.006 deciviews (90^{th} percentile) based on the three year average (0.008 deciviews based on the 98^{th} percentile). The Department considers this amount of improvement to be insignificant.

After considering all of the factors, the Department proposes that BART for filterable particulate matter when combusting lignite coal is no additional controls. Since current actual emissions are less than the current allowable emissions and emissions lower than the current allowable can be achieved by the existing control equipment, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu.

C. Condensible Particulate Matter (PM_{10}).

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by a spray dryer.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

AP-42, Compilation of Air Pollutant Emission Factors[2], suggests that the emission rate of condensible PM could be as high as 0.02 lb/10^6 Btu. This emission rate is approximately equal to the current emissions of filterable particulate matter. The emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensible particulate matter when combusting lignite coal is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Low Temperature Oxidation (LTO)
Non Selective Catalytic Reduction (NSCR)
Electro-Catalytic Oxidation (ECO)
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Flue Gas Recirculation (FGR)
Overfire Air (OFA)
Low NO_x Burners (LNB)
Pahlman Process

Step 2: Eliminate Technically Infeasible Options

After significant review, it is the Department=s position that high-dust SCR for control of emissions from the combustion of North Dakota lignite at electric utility steam generating units is not technically feasible at this time (see discussion in Appendix B.5). Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE.

ECO, NSCR and the Pahlman Process have not been demonstrated on a pulverized coal-fired boiler and are considered technically infeasible.

Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 1 since it is not a cyclone boiler.

Flue gas recirculation is not considered a technically feasible control option due to the space constraints at the facility. The space constraints do not allow for the additional ductwork and blower required to recirculate the flue gas.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department=s estimated emissions using the various technologies would be as follows:

Alternative	Control Efficiency (%)*	Emissions	
		(tons/yr)	(lb/10^6 Btu)
SCR with reheat	90	210	0.044
LTO	90	210	0.044
LNB + OFA + SNCR	45	1,156	0.239
SNCR	33	1,401	0.29
LNB + OFA	26	1,546	0.32
Baseline**	---	2,137	0.44

* Control efficiency provided in Great River Energy=s analysis.
** Based on the average of 2002 and 2003 emissions.

The estimated costs for the various technologies are as follows:

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
SCR with reheat	1,929	12,490,000	6,475	10,032*
LTO	1,929	44,780,000	23,217	45,439
LNB + OFA + SNCR	983	3,000,000	3,052	6,923**
SNCR	738	2,700,000	3,658	16,551
LNB + OFA	593	300,000	504	---
Baseline	2,137	---	---	---

* The incremental cost shown is the incremental cost of SCR with reheat as compared to LNB + OFA + SNCR.
** The incremental cost show is the incremental cost of LNB + OFA + SNCR as compared to LNB + OFA.

Step 4: Evaluate Impacts and Document Results

There are no energy or environmental impacts that would preclude the selection of any of the alternatives.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of the top two alternatives to be excessive. Modeling has been conducted assuming control with a spray dryer and LNB (current control for NO_x) and additional modeling has been conducted assuming control with OFA and SNCR in addition to the spray dryer and LNB. The difference in visibility impact between the two control scenarios is shown in the following tables.

Unit 1 - Lignite Coal Combustion Delta Deciview 90th Percentile				
Year	**Unit**	**LNB**	**LNB + OFA + SNCR**	**Difference**
2000	TRNP-SU	0.066	0.055	0.011
2001	TRNP-SU	0.061	0.054	0.007
2002	TRNP-SU	0.096	0.080	0.016
Average	*TRNP-SU*	0.074	0.063	0.011
2000	TRNP-NU	0.080	0.065	0.015
2001	TRNP-NU	0.089	0.073	0.016
2002	TRNP-NU	0.097	0.083	0.014
Average	*TRNP-NU*	0.089	0.074	0.015
2000	Elkhorn Ranch	0.054	0.049	0.005
2001	Elkhorn Ranch	0.036	0.034	0.002
2002	Elkhorn Ranch	0.074	0.060	0.014
Average	*Elkhorn Ranch*	0.055	0.048	0.007
2000	Lostwood W.A.	0.118	0.096	0.022
2001	Lostwood W.A.	0.160	0.133	0.027
2002	Lostwood W.A.	0.088	0.073	0.015
Average	*Lostwood W.A.*	0.122	0.101	0.021
Overall Average		0.085	0.0715	0.0135

Unit 1 - Lignite Coal Combustion Delta Deciview 98th Percentile				
Year	**Unit**	**LNB**	**LNB + OFA + SNCR**	**Difference**
2000	TRNP-SU	0.320	0.253	0.067
2001	TRNP-SU	0.322	0.261	0.061
2002	TRNP-SU	0.668	0.565	0.103
Average		0.437	0.360	0.077
2000	TRNP-NU	0.458	0.356	0.102
2001	TRNP-NU	0.385	0.318	0.067
2002	TRNP-NU	0.595	0.460	0.135
Average		0.479	0.378	0.101
2000	Elkhorn Ranch	0.224	0.215	0.009
2001	Elkhorn Ranch	0.241	0.203	0.038
2002	Elkhorn Ranch	0.517	0.426	0.091
Average		0.327	0.281	0.046
2000	Lostwood W.A.	0.340	0.260	0.08
2001	Lostwood W.A.	0.526	0.422	0.104
2002	Lostwood W.A.	0.410	0.334	0.076
Average		0.425	0.339	0.086
Overall Average		0.417	0.340	0.077

Step 6: Select BART

The Department considered the incremental cost of the top two options to be excessive. The Department proposes that BART is represented by low-NO_x burners (LNB) plus over-fire air (OFA) plus selective non-catalytic reduction (SNCR). The Department proposes that BART for NO_x when combusting lignite coal is an emission limit of 0.29 lb/million Btu on a 30-day rolling average basis.

IV. BART Evaluation of Unit 1 when Burning PRB

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer / Fabric Filter (SD/FF)
Circulating Dry Scrubber
Flash Dryer Absorber
Wet Scrubber with a 10% bypass
Dry Sorbent Injection / Fabric Filter (DSI/FF)
Dry Sorbent Injection / Existing ESP (DSI/ESP)
Powerspan ECO
Coal Cleaning
Pahlman Process

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals.[1] The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. The use of the K-Fuel process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Based upon the above, the Department does not consider coal cleaning or the K-Fuel process available or technically and economically feasible.

A circulating dry scrubber is not considered commercially available by Great River Energy. However, the Department is including this as an available technology. Costs for a circulating dry scrubber are estimated based on cost estimates included another BART analysis.

The Department considers the Powerspan ECO technology and the Pahlman Process not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Actual SO_2 emissions from Unit 1 at the Stanton Station were approximately 0.44 lb/million Btu heat input for calendar year 2006. However, Great River Energy has indicated that the mine from which the current PRB coal is received has a contractual arrangement with Great River to supply coal with a sulfur content which equates to an SO_2 emission limit no greater than 0.8 lb/million Btu heat input with a financial penalty if the sulfur content is greater than this amount. The mine uses a sulfur reject value of 1.2 lb/million Btu heat input.

Great River Energy has indicated that the contract for PRB coal from the existing mine expires in 2009 and has indicated that other potential PRB coal mines have PRB coal average sulfur contents of 0.34% sulfur, 0.64% sulfur and 0.80% sulfur, which equates to the following SO_2 emission rates:

SO_2 emission rate = 35S lb/ton*

* From EPA Publication AP-42, Section 1.1, Table 1.1-3, where S is the coal sulfur content.

SO_2 emission rate (at 0.34% sulfur PRB coal)
= 35 (0.34) lb/ton (1 ton/2,000 lb)(l lb / 9,350 Btu)
= 0.64 lb/million Btu heat input

SO_2 emission rate (at 0.64% sulfur PRB coal)
= 35 (0.64) lb/ton (1 ton/2,000 lb)(l lb / 8,750 Btu)
= 1.28 lb/million Btu heat input

SO_2 emission rate (at 0.80% sulfur PRB coal)
= 35 (0.80) lb/ton (1 ton/2,000 lb)(l lb / 8,750 Btu)
= 1.60 lb/million Btu heat input

For purposes of this analysis, an SO_2 emission rate of 1.2 lb/million Btu will be used to calculate uncontrolled emissions when combusting PRB coal. Baseline SO_2 emissions when combusting PRB coal are calculated using the heat inputs for calendar years 2001 and 2002, which are the same calendar years which were used to establish the baseline emission rate for SO_2 when combusting lignite coal. Baseline SO_2 emissions when combusting PRB coal assuming an SO_2 emission rate of 1.2 lb/million Btu are calculated as follows:

Heat input (2001) = 9.965×10^{12} Btu

Heat input (2002) = 1.075×10^{13} Btu

Average heat input = $(9.965 \times 10^{12} + 1.075 \times 10^{13}) / 2$
= 1.036×10^{13} Btu

Baseline SO_2 emission rate when combusting PRB coal
= 1.036×10^{13} Btu (1.2 lb/million Btu)(1 ton/2000 lb)
= 6,216 tons/year

The control effectiveness of all remaining control technologies assuming an SO_2 emission rate of 1.2 lb/million Btu are shown in the following table.

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Controlled Emissions	
			(tons/yr)	($lb/10^6$ Btu)
Wet Scrubber	95	6,216	311	0.06
Circulating Dry Scrubber	93	6,216	435	0.084
SD/FF	90	6,216	622	0.12
Flash Dryer Absorber	90	6,216	622	0.12
Wet Scrubber with 10% bypass	86	6,216	870	0.168
DSI/FF	55	6,216	2,797	0.54
DSI/ESP	35	6,216	4,040	0.78

The cost effectiveness and incremental costs for the various alternatives assuming an SO_2 emission rate of 1.2 lb/million Btu are shown in the following table.

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness($/ton)	Incremental Cost ($/ton)
Wet Scrubber	5,905	13,180,000	2,232	6,302****
Circulating Dry Scrubber	5,781	14,220,000***	2,460	16,043
SD/FF	5,594	11,220,000	2,006	1,283**
Wet Scrubber with 10% bypass	5,346	9,490,000	1,775	550
DSI/FF	3,419	8,430,000	2,466	4,208
DSI/ESP	2,176	3,200,000	1,471	---

Note: Flash Dryer Absorber is not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Great River Energy

** The incremental cost shown is the incremental cost of SD/FF compared to DSI/FF.

*** The cost is estimated based on costs included in the BART analysis for the Leland Olds Station.

**** The incremental cost shown is the incremental cost of a wet scrubber compared to SD/FF.

Given that a lower SO_2 emission rate of 0.64 lb/million Btu is possible in the future, baseline SO_2 emissions at this emission rate are calculated as follows:

Baseline SO_2 emission rate when combusting PRB coal
= 1.036 x 10^{13} Btu (0.64 lb/million Btu)(1 ton/2000 lb)
= <u>3,315 tons/year</u>

The control effectiveness of all remaining control technologies assuming an SO_2 emission rate of 0.64 lb/million Btu are shown in the following table.

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Controlled Emissions	
			(tons/yr)	(lb/10^6 Btu)
Wet Scrubber	95	3,315	166	0.032
Circulating Dry Scrubber	93	3,315	232	0.045
SD/FF	90	3,315	332	0.064

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Controlled Emissions	
			(tons/yr)	($lb/10^6$ Btu)
Flash Dryer Absorber	90	3,315	332	0.064
Wet Scrubber with 10% bypass	86	3,315	464	0.090
DSI/FF	55	3,315	1,492	0.288
DSI/ESP	35	2,215	2,155	0.416

The cost effectiveness and incremental costs for the various alternatives assuming an SO_2 emission rate of 0.64 lb/million Btu are shown in the following table.

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Wet Scrubber	3,149	13,180,000	4,185	11,807****
Circulating Dry Scrubber	3,083	14,220,000***	4,612	30,000
SD/FF	2,983	11,220,000	3,761	2,405**
Wet Scrubber with 10% bypass	2,851	9,490,000	3,329	1,031
DSI/FF	1,823	8,430,000	4,624	7,888
DSI/ESP	1,160	3,200,000	2,759	---

Note: Flash Dryer Absorber is not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Great River Energy

** The incremental cost shown is the incremental cost of SD/FF compared to DSI/FF.

*** The cost is estimated based on costs included in the BART analysis for the Leland Olds Station.

**** The incremental cost shown is the incremental cost of a wet scrubber compared to SD/FF.

Step 4: Evaluate Impacts and Document Results

Great River Energy has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the control equipment.

Step 5: Evaluate Visibility Results

The two primary alternatives are a wet scrubber operating at 95% removal efficiency and a spray dryer operating at 90% efficiency. The effects on visibility for each of these two control options at the Theodore Roosevelt National Park, South Unit (TRNP-SU), Theodore Roosevelt National Park, North Unit (TRNP-NU), Theodore Roosevelt National Park, Elkhorn Ranch (TRNP-Elkhorn Ranch) and the Lostwood Wilderness Area (Lostwood WA) were modeled when combusting lignite but not PRB. The degree of visibility improvement achieved by selecting a wet scrubber versus a spray dryer when combusting lignite does not exceed 0.028 deciviews (90^{th} percentile) or 0.112 deciviews (98^{th} percentile). The degree of incremental visibility improvement when combusting PRB is expected to be less than the incremental improvement when combusting lignite due to the lower SO_2 emission rates expected when combusting PRB.

Step 6: Select BART

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The incremental cost of greater than $16,000 per ton of SO_2 removed for a circulating dry scrubber compared to a spray dryer is considered excessive and a circulating dry scrubber is removed from further consideration as BART.

The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. The degree of visibility improvement achieved by selecting a wet scrubber operating at 95% control efficiency versus a spray dryer operating at 90% control efficiency is expected to be minimal. Although the amount of visibility improvement achieved by selecting a wet scrubber versus a spray dryer is small, the Department has placed the primary emphasis on the cost of each option. The incremental cost from a spray dryer to a wet scrubber is $6,302 per ton of SO_2 removed (assuming an uncontrolled emission rate of 1.2 lb/million Btu) and $11,807 per ton of SO_2 removed (assuming an uncontrolled emission rate of 0.64 lb/million Btu). The Department does not consider the incremental cost of $6,302 per ton to be excessive but does consider the incremental cost of $11,807 per ton to be excessive. Wet scrubbing does have additional environmental impacts as outlined below:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.
- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be

excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.

- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Based upon the additional environmental impacts and the fact that a wet scrubber will only remove at best an additional 311 tons/year of SO_2 (with a small corresponding visibility improvement) beyond the control achieved by a spray dryer, the Department proposes BART as a spray dryer with a fabric filter.

The calendar year average SO_2 emission rate used in the analysis is 1.2 lb/MM Btu when combusting PRB at Stanton Station Unit 1. As indicated previously, this is considered to be a reasonable estimate of the future annual average SO_2 emission rate when combusting PRB coal at Stanton Station Unit 1. Utilizing a 90% control efficiency for the spray dryer and fabric filter results in an annual average controlled SO_2 emission rate of approximately 0.12 lb/MM Btu. Based upon historical SO_2 emissions data for spray dryers and fabric filters at North Dakota facilities, the Department has determined that an increase of 33% is warranted to adjust from an annual average SO_2 emission rate to a 30-day rolling average SO_2 emission rate. Multiplying the annual average emission rate of 0.12 lb/MM Btu by a factor of 1.33 (an increase of 33%) yields a 30-day rolling average SO_2 emission rate of 0.16 lb/MM Btu. Therefore, BART for SO_2 when combusting PRB coal is an SO_2 emission limit of 0.16 lb/million Btu heat input on a 30 day rolling average basis or a reduction efficiency of 90% (on a 30-day rolling average basis) on the inlet SO_2 concentration to the pollution control equipment.

B. Filterable Particulate Matter

Section III.B. of this analysis proposes BART for filterable particulate matter (PM) when combusting lignite coal as no additional controls with an emission limit of 0.07 lb/million Btu heat input. Given that the available pollution control equipment is expected to control emissions from both lignite coal and PRB coal to similar expected emission rates, a BART analysis for filterable particulate matter when combusting PRB coal is expected to yield essentially the same results as the BART analysis for filterable PM when combusting lignite coal.

The Department has proposed BART for filterable PM when combusting lignite coal as no additional controls. The Department proposes that BART for filterable PM when combusting PRB coal is also no additional controls and proposes that BART is represented by an emission limit of 0.07 lb/million Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10})

Section III.C. of this analysis proposes BART for condensible particulate matter (PM) when combusting lignite coal is represented by sulfur dioxide control and good combustion control. For the same reasons outlined in Section III.C. for the selection of BART for condensible PM when combusting lignite coal, the Department proposes that the BART limit for sulfur dioxide when combusting PRB coal can act as a surrogate for condensible particulate matter along with a requirement for good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Low Temperature Oxidation (LTO)
Non Selective Catalytic Reduction (NSCR)
Electro-Catalytic Oxidation (ECO)
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Flue Gas Recirculation (FGR)
Overfire Air (OFA)
Low NO_x Burners (LNB)
Pahlman Process

Step 2: Eliminate Technically Infeasible Options

After significant review, it is the Department=s position that high-dust SCR for control of emissions from the combustion of North Dakota lignite at electric utility steam generating units is not technically feasible at this time (see discussion in Appendix B.5). Great River Energy has included a cost estimate for low-dust SCR, while high-dust SCR is listed as technically infeasible by GRE. Although high-dust SCR is considered technically feasible by the Department when combusting PRB coal, the fact that lignite coal will be allowed to be combusted in the future in Unit 1 does not allow for the installation of a high-dust SCR system; therefore, a high-dust SCR system remains technically infeasible for Unit 1.

ECO, NSCR and the Pahlman Process have not been demonstrated on a pulverized coal-fired boiler and are considered technically infeasible.

Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 1 since it is not a cyclone boiler.

Flue gas recirculation is not considered a technically feasible control option due to the space constraints at the facility. The space constraints do not allow for the additional ductwork and blower required to recirculate the flue gas.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Great River Energy calculated the baseline emission rate for NO_x when combusting PRB coal using an emission rate of 0.36 lb/million Btu (as compared to the baseline emission rate when burning lignite of 0.435 lb/million Btu), resulting in a baseline emission rate when combusting PRB coal of 1,740 tons/year. The Department=s estimated emissions using the various technologies would be as follows:

Alternative	**Control Efficiency (%)***	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)****
SCR with reheat	88	210	0.044
LTO	88	210	0.044
LNB + OFA + SNCR	45	946	0.196
SNCR	36	1,111	0.230
LNB + OFA	21	1,382	0.286
Baseline	---	1,740	0.36

* Control efficiencies calculated based upon the lb/million Btu emission rates provided by Great River Energy.

** Provided by Great River Energy.

The estimated costs for the various technologies are as follows:

Alternative	**Emissions Reduction (tpy)**	**Annualized Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
SCR with reheat	1,530	12,490,000	8,163	12,894*
LTO	1,530	44,780,000	29,268	60,842
LNB + OFA + SNCR	794	3,000,000	3,778	6,193**
SNCR	629	2,700,000	4,293	8,856
LNB + OFA	358	300,000	838	---
Baseline	1,740	---	---	---

* The incremental cost shown is the incremental cost of SCR with reheat as compared to LNB + OFA + SNCR.

** The incremental cost show is the incremental cost of LNB + OFA + SNCR as compared to LNB + OFA.

Step 4: Evaluate Impacts and Document Results

There are no energy or environmental impacts that would preclude the selection of any of the alternatives.

Step 5: Evaluate Visibility Impacts

The Department considers the incremental cost effectiveness of the top two alternatives to be excessive. Modeling has been conducted to estimate visibility impacts when combusting lignite but not PRB. When combusting lignite, the degree of visibility improvement achieved by selecting a low-NO_x burner plus over-fire air and SNCR over a low NO_x burner plus over-fire air was shown to be no greater than 0.027 deciviews (90^{th} percentile) and 0.135 deciviews (98^{th} percentile). The degree of incremental visibility improvement when combusting PRB is expected to be less than the incremental improvement when combusting lignite due to the lower NO_x emission rates expected when combusting PRB.

Step 6: Select BART

The Department considers the cost effectiveness and the incremental cost of the top two options to be excessive. The cost for the third option (LNB + OFA + SNCR) is not considered to be excessive. The Department proposes that BART is represented by low-NO_x burners (LNB) plus over-fire air (OFA) plus selective non-catalytic reduction (SNCR). The Department proposes that BART when combusting PRB coal is an emission limit of 0.23 lb/10^6 Btu on a 30-day rolling average basis.

V. BART Evaluation for Auxiliary Boiler

The auxiliary boiler is a #2 fuel-oil fired boiler with a nominal rating of 38 x 10^6 Btu/hr. The auxiliary boiler is only used when both units at the Stanton Station are down. During the baseline period (2000-2004), the unit was operated a total of 93 hours. The annual average emissions from the unit for this period were:

NO_x	0.14 tons
SO_2	0.36 tons
PM	0.02 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls. The current permit limits the fuel used in the boiler to #2 fuel oil. BART is the use of #2 fuel oil.

VI. BART Evaluation for Emergency Diesel Generator

The emergency diesel generator has a rated heat input of 10.35 million Btu/hr. The generator is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. Assuming 500 hours/year of operation, emissions from the unit would be as follows.

NO_x	8.0 tons
SO_2	1.3 tons
PM	0.2 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Emergency Fire Pump

The emergency fire pump is driven by a 370 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. Assuming a maximum of 500 hours of operation per year, emissions would be as follows:

NO_x	2.76 tons
SO_2	0.19 tons
PM	0.2 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VIII. BART Evaluation for Materials Handling Sources

The materials handling sources at the Stanton Station that emit to the atmosphere are as follows:

EUI	**Description**	**Existing Control Equipment**	**Current Emission Limit (lb/hr)**	**Baseline Emissions (tons/yr)**
M1	Unit 1 Coal Bunker	Baghouse	5.0*	0.6**
M3	Unit 2 West bunker conveyor	Baghouse	5.0	18.3**

* The emission limit of 5.0 lb/hr is for combined emissions from the Unit 1 and Unit 10 coal bunkers.

** Department estimate.

The materials handling units are controlled using a baghouse which is considered the most efficient control device. Therefore, the Department proposes that BART for the materials handling units is no additional controls and the current emission limit for the units is BART.

IX. Summary

The proposed BART limits and the effect on emissions is shown in the following table.

Source Unit	Proposed BART Limit/Work Practice				Emissions Reduction (tons/yr)		
	PM	SO_2	NO_x	Units	PM	SO_2	NO_x
Unit 1 Boiler (lignite)	0.07	0.24	0.29	lb/10^6 Btu	0	7,715	983
Unit 1 Boiler (PRB)	0.07	0.16	0.23	lb/10^6 Btu	0	5,594	794
Auxiliary Boiler	Use #2 Fuel Oil			N/A	0	0	0
Emergency Diesel Generator	Use #2 Fuel Oil			N/A	0	0	0
Fire Pump	Use #2 Fuel Oil			N/A	0	0	0
M1	5.0	---	---	lb/hr	0	---	---
M3	5.0	---	---	lb/hr	0	---	---
Total (lignite)					0	7,715	983
Total (PRB)					0	5,594	794

The BART analyses for SO_2 and NO_x were conducted assuming 100% lignite combustion and 100% PRB coal combustion. Since the same technologies were chosen for both fuels, any BART analysis conducted assuming a blending of lignite and PRB coal would result in the choice of the same control technologies as BART. For this reason, separate BART analyses conducted assuming a blending of coals were not necessary and were not conducted. However, to account for the scenario when both lignite coal and subbituminous coal are burned together in a 30-day averaging period, SO_2 and NO_x emissions will be limited by a weighted average emission limit when burning a combination of lignite and subbituminous coal. It should be noted that lignite and PRB coal will likely only be burned in the same 30-day averaging period during a switch from one coal to another (i.e., fuel blending is not likely to occur on an extended basis).

The modeled visibility impacts of Unit 1 when combusting lignite coal are shown in the following tables. As can be seen from the tables below, the proposed BART limits will result in average modeled visibility improvements ranging from 69-75% in the Class I areas when combusting lignite coal. The overall average improvement (90^{th} percentile) for all Class I areas is approximately 0.2 deciviews, which equates to a 73% improvement. The overall average improvement (98^{th} percentile) for all Class I areas is approximately 0.8 deciviews, which equates to a 70% improvement.

Modeling was not conducted to determine the visibility impacts when combusting PRB coal; however, since the proposed BART limits are lower for PRB (when compared to lignite), the visibility improvement when combusting PRB coal is expected to be greater than the visibility improvement when combusting lignite.

Unit 1 - Lignite Coal Combustion Delta Deciview 90^{th} Percentile					
Year	**Unit**	**Existing Impact**	**BART Controls**	**Difference**	**Percent Improvement**
2000	TRNP-SU	0.228	0.055	0.173	76
2001	TRNP-SU	0.214	0.054	0.160	75
2002	TRNP-SU	0.310	0.080	0.230	74
Average	*TRNP-SU*	*0.251*	*0.063*	*0.188*	*75*
2000	TRNP-NU	0.221	0.065	0.156	71
2001	TRNP-NU	0.319	0.073	0.246	77
2002	TRNP-NU	0.312	0.083	0.229	73
Average	*TRNP-NU*	*0.284*	*0.074*	*0.210*	*74*
2000	Elkhorn Ranch	0.184	0.049	0.135	73
2001	Elkhorn Ranch	0.144	0.034	0.110	76
2002	Elkhorn Ranch	0.233	0.060	0.173	74
Average	*Elkhorn Ranch*	*0.187*	*0.048*	*0.139*	*74*
2000	Lostwood W.A.	0.344	0.096	0.248	72
2001	Lostwood W.A.	0.386	0.133	0.253	66
2002	Lostwood W.A.	0.308	0.073	0.235	76
Average	*Lostwood W.A.*	*0.346*	*0.101*	*0.245*	*71*
Overall Average		**0.267**	**0.072**	**0.196**	**73**

Unit 1 - Lignite Coal Combustion Delta Deciview 98th Percentile					
Year	**Unit**	**Existing Impact**	**BART Controls**	**Difference**	**Percent Improvement**
2000	TRNP-SU	0.937	0.253	0.684	73
2001	TRNP-SU	0.901	0.261	0.640	71
2002	TRNP-SU	1.675	0.565	1.110	66
Average	*TRNP-SU*	*1.171*	*0.360*	*0.811*	*70*
2000	TRNP-NU	0.947	0.356	0.591	62
2001	TRNP-NU	1.205	0.318	0.887	74
2002	TRNP-NU	1.540	0.460	1.080	70
Average	*TRNP-NU*	*1.231*	*0.378*	*0.853*	*69*
2000	Elkhorn Ranch	0.868	0.215	0.653	75
2001	Elkhorn Ranch	0.733	0.203	0.530	72
2002	Elkhorn Ranch	1.432	0.426	1.006	70
Average	*Elkhorn Ranch*	*1.011*	*0.281*	*0.730*	*72*
2000	Lostwood W.A.	0.991	0.260	0.731	74
2001	Lostwood W.A.	1.351	0.422	0.929	69
2002	Lostwood W.A.	1.150	0.334	0.816	71
Average	*Lostwood W.A.*	*1.164*	*0.339*	*0.825*	*71*
Overall Average		**1.144**	**0.340**	**0.805**	**70**

X. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate loading to the scrubber shall be accomplished by either:

   a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.

Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

References

1. K-fuels website, 2007. www.evgenergy.com

2. EPA, 1995. Compilation of Air Pollutant Emission Factors Volume 1: Stationary Point and Area Sources. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

3. Great River Energy, 2008. Stanton Station Unit 1 BART Analysis; Revised January 2008.